NON-PUBLIC?: N
ACCESSION #: 9308020039
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Fort Calhoun Station Unit No. 1 PAGE: 1 OF 10

DOCKET NUMBER: 05000285

TITLE: Reactor Trip on Loss of Load During Switchyard
Maintenance
EVENT DATE: 06/24/93 LER #: 93-011-00 REPORT DATE: 07/26/93

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Craig E. Booth, Shift Technical TELEPHONE: (402) 533-6874
Advisor

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EA COMPONENT: 27 MANUFACTURER: A109
X SD RV K235
X SJ P B580
REPORTABLE NPRDS: Y
Y
Y

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On June 24, 1993 at 1322, the Fort Calhoun Station (FCS) experienced a reactor trip due to a Loss of Load. Work was in progress in the FCS switchyard involving Type SBFU Static Circuit Breaker Failure Relays, when a door mounted Type AR relay was inadvertently actuated. This, in turn, tripped two breaker failure lock-out relays, which resulted in opening of station output breakers and de-energized both 4.16kV non-vital buses. One non-vital bus failed to properly load shed on the loss of voltage, and as a result breakers remained closed on the bus even though the bus was de-energized. Initial Operator actions, based on Control Room indications that these breakers were closed, resulted in a

short-term interruption of feedwater and condensate flow.

This event was determined to have resulted from lack of proper job planning, lack of a formal decision making process, incomplete communications and inadequate implementation of a procedure.

Corrective actions include actions to improve the conduct of work within the switchyard, and training for Operations personnel on use of all available indications in decision making.

END OF ABSTRACT



BACKGROUND

The Fort Calhoun Station (FCS) Main Generator supplies 22kV power to the Main Transformer T1 and to the two Unit Auxiliary Transformers T1A-1 and T1A-2 (see Figure 1). Transformer T1 steps 22kV power from the main generator up to 345kV which is then supplied to the Midcontinent Area Power Pool (MAPP) grid. FCS is connected to the grid via a ring bus in the station switchyard. Connections to three 345kV transmission lines are provided by the ring bus, each of which has the capacity to carry the station output. Breaker arrangement allows each line, as well as FCS, to be isolated from the ring bus. The normal output arrangement has FCS connected to the ring bus via both output breakers, 3451-4 and 3451-5, and all 345kV lines available. Either Breaker 3451-4 or Breaker 3451-5 can be open with the station operating at or above 15% of rated power. If both breakers are opened above 15% power, a Loss of Load reactor trip will be initiated.

Breakers 3451-4 and 3451-5 each have associated breaker failure relays. These relays are intended to isolate the affected breaker and de-energize all sources that could potentially feed into the failed breaker. For Breaker 3451-5, one breaker failure lock-out relay, 86-1/BF5 trips 345kV Breakers 3451-4 and 3451-6, and sends a direct transfer trip to isolate the remote end of Circuit 3424. The second lock-out relay, 86-2/BF5 trips Generator Field Breaker 41E/G1F, Turbine Master Trip 94 MTR, and 4.16kV Breakers 1A11, 1A13, 1A22, and 1A24.

The two Unit Auxiliary Transformers, T1A-1 and T1A-2, step down the 22kV power supplied by the Main Generator to 4.16kV. These transformers are the normal power supplies for non-vital 4.16kV Buses 1A1 and 1A2 respectively. The normal power supply for the two vital 4.16kV buses, 1A3 and 1A4, is an offsite 161kV line. Although the normal alignment has the non-vital buses supplied from 22kV and the vital buses supplied from

161kV, various arrangements are possible, including all four 4.16kV buses being supplied from 161kV.

EVENT DESCRIPTION

OPPD received a Product Advisory Letter dated May 19, 1993, from ASEA Brown Boveri (ABB) that outlined the results of an investigation into a false trip of a Type SBFU Static Circuit Breaker Failure Relay. The letter indicated that a false trip could be caused by an unintentional ground of one or more ZA/RC Zener diode/resistor circuits. The ABB letter indicated that accidental grounding of the components discussed could be prevented by affixing Nomex insulation with an adhesive backing inside the SBFU top cover. In response to the ABB Product Advisory Letter, the OPPD System Protection Department issued work orders to install Nomex insulation in all Type SBFU relays, including five located in the FCS switchyard.



On June 24, 1993, the plant was operating in Mode 1 at a nominal 100% power. The 4.16kV buses were in a normal alignment with non-vital Buses 1A1 and 1A2 being powered from 22kV, and vital Buses 1A3 and 1A4 being powered from offsite 161kV. Loading on the 4.16kV buses included the following components:

Bus 1A1 Reactor Coolant Pump RC-3A, Condensate Pump FW-2A, Circulating Water Pump CW-1A
Bus 1A2 Reactor Coolant Pump RC-3B, Condensate Pump FW-2B, Feedwater Pump FW-4B, Circulating Water Pump CW-1B
Bus 1A3 Reactor Coolant Pump RC-3C, Raw Water Pump AC-10A
Bus 1A4 Reactor Coolant Pump RC-3D, Feedwater Pump FW-4C, Circulating Water Pump CW-1C, Raw Water Pump AC-10B.

Buses 1A3 and 1A4 were also supplying the 480V and lower buses in a normal electrical lineup.

At approximately 1245, a Senior Relay Specialist (SRS) and a Dispatching Department Trainee contacted the FCS Control Room via telephone and informed them that they would be working in the switchyard. The nature of the work to be performed, installation of Nomex insulation, was not specifically discussed. The Control Room Operator believed this involved continuation of work, on a non-plant related transformer, which had been started earlier in the day.

After successfully installing Nomex in the Type SBFU Relay for Breaker 3451-6, the SRS proceeded to open the back door of the Type SBFU Relay for Breaker 3451-5. While opening the door, the SRS found the door latch to be "a little tight." Using the same manner as for the previous relay, the SRS operated the door knob button, while the other hand was holding the door surface, and opened the door with both hands. The SRS knew that there was a sensitive Type AR relay mounted on the back side of the door of the Type SBFU Breaker Relay Unit.

As the SRS opened the cabinet door, he heard breakers operate. The motion of operating the door knob button and opening the door apparently caused a localized vibration on the door, closing the contacts of the Type AR relay and tripping Breaker Failure Lock-out Relays 86-1/BF5 and 86-2/BF5. The tripping of the breaker failure lock-out relays resulted in additional actuations which isolated FCS from the grid, isolated the non-vital 4.16kV buses from the Unit Auxiliary Transformers, and initiated a turbine trip and reactor trip. The reactor trip, on Loss of Load, was received at 1322. Non-vital Buses 1A1 and 1A2 which had been receiving power from the Unit Auxiliary Transformers, were de-energized. Vital Buses 1A3 and 1A4 remained energized.



The loss of voltage on Bus 1A1 resulted in initiation of a load shed signal which opened breakers on Bus 1A1. The corresponding load shed signal for Bus 1A2 failed to actuate. As a result, the breakers for loads on Bus 1A2 remained closed and the control switch lights in the Control Room indicated that the breakers were closed on the bus.

As a result of the loss of power to Buses 1A1 and 1A2, two of four reactor coolant pumps, both running condensate pumps, and one of the two operating feedwater pumps, were de-energized. The third condensate pump, FW-2C, powered from Bus 1A4, automatically started. Both Emergency Diesel Generators started to idle speed and did not load. Charging Pump CH-1C started due to level deviation in the pressurizer. The Emergency Diesel Generator and charging pump starts were normal and expected responses for this transient.

In response to the reactor trip the Control Room operators immediately entered Emergency Operating Procedure EOP-00, "Reactor Trip Recovery." As part of the standard post-trip actions, at approximately 1323, the Secondary Reactor Operator (RO) selected one feedwater pump and one condensate pump for operation. The RO selected FW-4B and FW-2B as the pumps for operation and secured FW-4C and FW-2C. This selection of pumps was based on operator training which indicated that FW-4B and FW-2B are the preferred pumps for operation, if available. The Secondary RO was using only the breaker indication (which showed the breakers for FW-4B and FW-2B were closed on Bus 1A2) when making the selection and did not realize that Bus 1A2 and its associated equipment was de-energized.

At 1326, the Secondary RO noted that Steam Generator (SG) levels were not recovering as expected. The Secondary RO determined that no feedwater pumps were in operation. The Operator then started Auxiliary Feedwater Pump FW-6 and re-established feedwater flow from the Emergency Feedwater Storage Tank, through the main feedwater feedring, into the SGs. Feedwater flow was re-established well before an automatic actuation of auxiliary feedwater would be received.

At approximately 1337, the Control Room received a report of steam in the vicinity of Feedwater Heater FW-15A. Non-licensed and relief shift personnel were dispatched to FW-15A to determine the cause. Feedwater Heater Relief Valve FW-1425 was found to have lifted and stuck open. The situation was reported to the Control Room, and actions were taken to isolate the feedwater heater.

The diagnostic actions at the conclusion of EOP-00 were completed and at approximately 1339, EOP-02, "Loss of Offsite Power/Loss of Forced Circulation," was entered.



At approximately 1340, the Control Room began to receive reports of water hammer in the turbine building. The Licensed Senior Operator (LSO) directed the Secondary RO to restart FW-2C, which had been secured during the post trip actions. At approximately 1343, FW-2C was restarted, terminating the water hammer.

Feedwater pump seal leakage was also reported to the Control Room during the event.

At approximately 1354, Buses 1A1 and 1A2 were re-energized. The plant was maintained in Hot Shutdown (Mode 3). At 1830, with the plant condition stable, power restored to 4.16kV Buses 1A1 and 1A2, and the exit conditions for EOP-02 satisfied, the Emergency Operating Procedures were exited.

The NRC was notified of the event on June 24, 1993 at 1421, pursuant to 10 CFR 50.72(b)(2)(ii). This report is being submitted pursuant to 10 CFR 50.73(a)(2)(iv).

SAFETY ASSESSMENT

This event resulted in an actuation of the Reactor Protective System, and a loss of power to non-vital 4.16kV buses. It did not, however, pose a danger to the public. Loss of Load is an analyzed plant transient and plant response was within the predicted response parameters.

Equipment challenges that occurred during the course of the event (i.e., loss of power to non-vital 4.16kV buses, failure of Bus 1A2 to load shed, Feedwater Heater Relief Valve FW-1425 sticking open, water hammer in the vicinity of the Steam Packing Exhauster and damage to feedwater pump seals) did not affect the ability to safely shut down the reactor and maintain the reactor in a safe shutdown condition. The Class 1E safety-related 4.16kV buses (1A3 and 1A4) were not affected by the event. The 161kV power source continued to supply power throughout the event to the Class 1E buses and, in addition, the Emergency Diesel Generators started and were available for service.

CONCLUSIONS

The post-event investigation addressed both the cause of the Loss of Load and several issues regarding the plant response to the event. The investigation included a Human Performance Enhancement System (HPES) evaluation which focused on switchyard activities, and a Root Cause Analysis (RCA) which focused on several aspects of the plant response to the event.



The HPES evaluation indicated that the event resulted from inappropriate action, in that opening the door to the Type SBFU relay apparently jarred the Type AR relay which subsequently actuated the lock-out relays. Four causes of the inappropriate action were identified:

1. Lack of proper job planning, in that test switches were not placed in the open position to disable the output of the lock-out relays,
2. Lack of a formal decision making process on what work should/can be done on-line,
3. Incomplete communications between personnel in the switchyard and personnel in the Control Room, and
4. Inadequate implementation of procedure NOD-QP-36, "Control of Switchyard Activities at Fort Calhoun Station. 11

With respect to the plant response to the event, the RCA addressed five specific issues. The first issue addressed by the RCA was to investigate whether non-vital Buses 1A1 and 1A2 should have automatically transferred to the 161kV power supply following loss of the 22kV power supply. Circuitry is provided for two types of automatic transfer, "Fast" transfer (designed to occur within 6 to 8 cycles and "Slow" transfer (designed to occur within seven seconds). The review determined that there was no failure in the automatic transfer circuitry.

Specifically, fast transfer did not occur because station output breakers and the generator field breaker were tripped as a result of Breaker Failure Lock-out Relays 86-1/BF5 and 86-2/BF5 being tripped. This prevented the turbine trip lock-out relay 86-1/SVG1 from actuating and, by design, prevented fast transfer. This is to ensure that the buses will not be transferred into a fault as sensed by the breaker failure relays.

The slow transfer circuitry was also found to have functioned as designed. Two conditions required for a successful slow transfer are a load shed, and the connected source must be de-energized within a seven second window. The investigation revealed that the auxiliary undervoltage relays associated with slow transfer did not actuate until the seven second window had elapsed. This was because the coast-down of the main generator and the impedance of the transformer load delayed the decay of the secondary transformer voltage until the seven second window was closed. In addition, for Bus 1A2, the failure to load shed would have prevented the slow transfer.



The second issue addressed by the RCA was the failure of Bus 1A2 to load shed after it was de-energized. The failure of Bus 1A2 to load shed could not be reproduced during troubleshooting. Three functional tests of the load shed circuitry were performed and all sensing and actuation relays functioned properly. No abnormalities in the sensing or actuation circuitry were identified. It has been postulated that the Agastat timing relay (27T1/1A2) output contact may have been dirty, thus preventing Bus 1A2 load shed. However, that relay did function properly in subsequent functional tests. The design of the loss of voltage load shed circuitry for the non-vital buses (1A1 and 1A2) provides less built-in redundancy than circuitry for the vital buses (1A3 and 1A4).

The third issue addressed by the RCA was the failure of relief valve FW-1425 to reseat. Valve FW-1425 was bench tested to determine the lift setpoint and then inspected to determine why it did not reseat. The bench test showed that no drift in setpoint had occurred. The valve lifted at 700 psig as designed. Inspection of the internals revealed that the failure to reseat was due to a possible misalignment of the disk, stem and disk guide; and interference between the disk and the disk guide due to foreign material buildup on moving surfaces.

The fourth issue addressed by the RCA was the occurrence of water hammer in the Condensate System in the vicinity of the Steam Packing Exhauster (SPE). During the event, the Secondary RO inappropriately tripped the only operating condensate pump. This action resulted from over-reliance on a single indication (i.e., the breaker position indications). The indication used was accurate in that the pump motor breaker was closed on the bus, but misleading in that the bus was not energized. The failure of Bus 1A2 to properly load shed resulted in this situation.

With condensate flow stopped, the water in the SPE tube bundle started to boil. The steam void rose from the SPE until it contacted cooler water in the condensate system. This collapsed the steam void and accelerated water back towards the SPE. Since the SPE is the only condensate system component in the area that is anchored (others are free to move due to thermal expansion/contraction experienced during startup and shutdown) it experienced the most damage.

The only identified damage to the SPE was one broken anchor bolt. The remaining anchor bolts were determined to be adequate to ensure proper operation of the SPE. The inspections made showed that no observable deformation of the piping occurred. The piping movements were judged to be within reasonable limits. Additionally the condensate, main feedwater, and main steam systems were walked down with no additional damage discovered.



The fifth and final issue addressed by the RCA was the failure of Feedwater Pump FW-4B seals. The seals to FW-4B failed due to a combination of aging and a spike in the feedwater header pressure. The spike occurred when the Secondary RO established auxiliary feedwater to the Steam Generators. The seals were near the end of their service life at the time of failure and therefore susceptible to failure due to pressure shocks. The failure of these seals was determined to be insignificant to this event.

CORRECTIVE ACTIONS

With respect to the switchyard activities that initiated the event, the following corrective actions have been or will be completed:

1. A memorandum was issued to Operations personnel regarding management expectations with respect to switchyard activities, emphasizing the requirements of NOD-QP-36. Also, on-shift training was provided to Licensed Operators on NOD-QP-36.

2. Appropriate Electric Operations Division personnel have been briefed on the requirements of NOD-QP-36.

3. System Operation Danger Tags have been placed on switchyard cabinets that contain Type AR relays. These tags will be replaced with permanent tags during the next refueling outage.

4. Procedure NOD-QP-36 will be revised by August 15, 1993, to better define the type of work that can be done on-line and the type of work that is high risk, and to enhance and formalize the communication and work planning/review process among divisions (i.e., the Nuclear Operations Division, the Electric Operations Division and the Production Operations Division). In addition, a checklist will be developed for NOD-QP-36 that will be used by appropriate personnel to assist them in ensuring that they understand the scope of work to take place, and that switchyard issues are properly addressed. In addition, this will ensure that personnel in the switchyard understand the needs of the Control Room when they conduct work on switchyard equipment.

5. A key card reader, with an associated alarm, will be installed by August 31, 1993, to restrict entry into the switchyard. As an interim measure, FCS locks, in addition to the already installed OPPD locks, have been installed on switchyard entry gates to ensure that the Control Room is notified prior to switchyard entries.



6. A training program will be established by September 15, 1993 for Electric Operations Division personnel, on the revised version of NOD-QP-36 (see Item 4 above). Completion of this training will be required prior to receiving routine access to the FCS switchyard.

7. A training program will be established by September 15, 1993 for Operations personnel, on switchyard equipment and relaying, to enhance their ability to evaluate the risk associated with switchyard activities.

With respect to the plant response to the event, the following corrective actions have been or will be completed:

1. As previously noted, troubleshooting was performed with respect to the failure of Bus 1A2 to properly load shed. No

abnormalities were identified.

2. Feedwater Heater Relief Valve FW-1425 was replaced with a relief valve of improved design. The new valve was bench tested prior to installation. Other feedwater heater tube-side relief valves were bench tested and six of eleven valves failed to lift at their design setpoint. These valves were then repaired as required, and re-installed. A twelfth valve (FW-1465), which could not be isolated for removal, will be tested during the 1993 Refueling Outage. These valves will be included in a Relief Valve Reliability Program by December 31, 1993, which will address periodic testing and maintenance to ensure reliability.

3. With respect to water hammer damage, the Steam Packing Exhauster and connected piping were inspected, and the only damage identified was a broken anchor bolt. The remaining bolts were determined to be adequate for operation.

4. Training will be provided to Operations personnel by November 1, 1993, emphasizing the importance of using all available indications (e.g., motor breaker position indication and motor amps) to avoid inappropriate actions.

5. The seals on Feedwater Pump FW-4B have been repaired. Feedwater Pump FW-4A had some existing seal leakage prior to the event and was also repaired.

PREVIOUS SIMILAR EVENTS

No recent similar events have been identified involving a reactor trip due to switchyard activities.



Figure 1 omitted.



Omaha Public Power District
P. O. Box 399 Hwy.75-North of Ft. Calhoun Fort Calhoun, NE 68023-0399
402/636-2000

July 26, 1993
LIC-93-0190

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-137
Washington, DC 20555

Reference: Docket No. 50-285

Gentlemen:

Subject: Licensee Event Report 93-011 for the Fort Calhoun Station

Please find attached Licensee Event Report 93-011 dated July 26, 1993. This report is being submitted pursuant to 10 CFR 50.73(a)(2)(iv). If you should have any questions, please contact me.

Sincerely,

W. G. Gates
Vice President

WGG/jrg

Attachment

c: J. L. Milhoan, NRC Regional Administrator, Region IV
S. D. Bloom NRC Project Manager
R. P. Mullikin, NRC Senior Resident Inspector
INPO Records Ce
ter

45.5129

*** END OF DOCUMENT ***